U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-268 958

Evaluation of the Technological Feasibility, and Cost of Selected Control Alternatives Necessary to Meet the Proposed Ohio SO2 Regulations for Industrial Boilers and Processes. Volume V. Phillips Petroleum Toledo Philblack Plant, Carbon Black

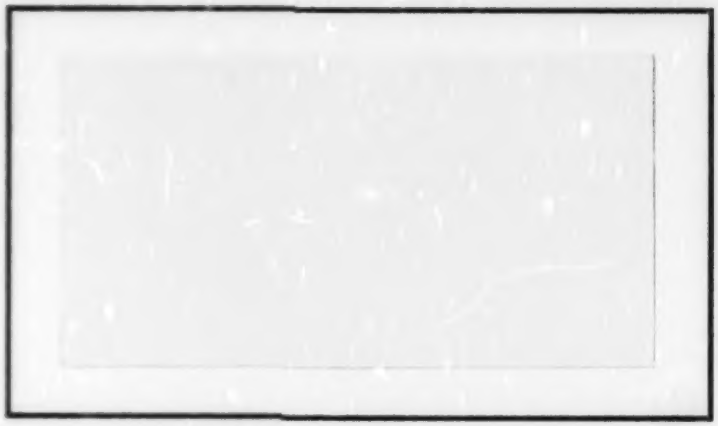
GCA Corp, Bedford, Mass. GCA Technology Div.

Prepared for

Environmental Protection Agency, Chicago, Ill. Air and Hazardous Materials Div.

Aug 76

PB 268 958



GCA/TECHNOLOGY DIVISION

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

EPA-905/2-76-005-e

GCA-TR-76-14-G(5)

EVALUATION OF THE TECHNOLOGICAL FEASIBILITY, AND COST OF SELECTED CONTROL ALTERNATIVES NECESSARY TO MEET THE PROPOSED OHIO SO_2 REGULATIONS FOR INDUSTRIAL BOILERS AND PROCESSES

FINAL REPORT

Contract No. 68-01-3155
Task Order No. 4

August 1976

Volume V

PHILLIPS PETROLEUM
TOLEDO PHILBLACK PLANT,
CARBON BLACK

by

Hans A. Klemm
Robert R. Hall

GCA CORPORATION
GCA/TECHNOLOGY DIVISION
Bedford, Massachusetts

EPA Contract Officer

Wayne E. Pearson
Air Policy Branch, A&HMD
Environmental Protection Agency, Region V
230 South Dearborn Street
Chicago, Illinois 60604

U.S. ENVIRONMENTAL PROTECTION AGENCY
Division of Stationary Source Enforcement
Washington, D.C. 20460

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-905/2-76-005-e		

4. TITLE AND SUBTITLE
Evaluation of the Technological Feasibility and Cost of Selected Alternatives Necessary to Meet the Proposed Ohio SO_2 Regulations for Industrial Boilers and Processes. Volume V

5. REPORT DATE
August 1976

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
Hans A. Klemm
Robert R. Hall

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
GCA Corporation
GCA/Technology Division
Bedford, Massachusetts

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
68-01-3155
Task Order No. 4

12. SPONSORING AGENCY NAME AND ADDRESS
Air Programs Branch, A&HMD
Environmental Protection Agency, Region V
230 S. Dearborn
Chicago, Illinois 60604

13. TYPE OF REPORT AND PERIOD COVERED
Final

14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES
One of 9 documents supporting sulfur dioxide control strategy for the State of Ohio Technical Support Document Volumes I and II EPA 905/2-76-002

16. ABSTRACT

This report presents an evaluation by the GCA Corporation, GCA/Technology Division, of technological feasibility and cost of complying with the proposed Ohio sulfur dioxide regulation (40 FR 52410, November 10, 1975) at the Phillips Petroleum Company's Toledo Philblack Plant. The final USEPA Sulfur Dioxide Control Strategy for the State of Ohio Technical Support Documents, Vol. I and II, (EPA 905/2-76-002) may be obtained from NTIS.

This plant manufactures carbon black by the oil furnace process. Sulfur dioxide emissions occur from the combustion of off-gasses in product dryers, an incinerator, and CO boilers. The technological feasibility of flue gas desulfurization by the double alkali process (FMC) and by the lime process (Research-Cottrell) was evaluated along with cost of compliance for the latter process.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Carbon Black Desulfurization Sulfur Dioxide	Control Strategy Ohio Oil Furnace Phillips Petroleum Company	13B

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)*	22. PRICE

47

A03 - A01

EPA Form 2220-1 (9-73)

This Final Report was furnished to the Environmental Protection Agency by the GCA Corporation, GCA/Technology Division, Bedford, Massachusetts 01730, in fulfillment of Contract No. 68-01-3155, Task Order No. 4. The opinions, findings, and conclusions expressed are those of the authors and not necessarily those of the Environmental Protection Agency or of the cooperating agencies. Mention of company or product names is not to be considered as an endorsement by the Environmental Protection Agency.

ABSTRACT

Phillips Petroleum Company's Toledo Philblack Plant manufactures carbon black by the oil furnace process. SO_2 emissions occur from combustion of off gases in product dryers, an incinerator and CO boilers. The results of an evaluation of the technical feasibility and cost of complying with the proposed Ohio SO_2 regulation at this facility are presented in this report.

CONTENTS

		Page
Abstract		iii
List of Figures		v
List of Tables		vi
Acknowledgments		vii
Sections		
I	Summary and Conclusions	1
II	Process and Site Description	3
III	SO_2 Control Technology	16
IV	Cost of SO_2 Control	29
V	References	36

FIGURES

No.		Page
1	Phillips Petroleum Company Toledo Philblack Plant Process Flowsheet	5
2	R-C Lime (Bahco) Scrubber System	19
3	FMC Double Alkali Scrubber System	23

TABLES

No.		Page
1	Original Process Data From Operating Permits Based on 1.7 Percent Sulfur Feedstock	8
2	SO_2 Emission Data for the CO Boilers	10
3	SO_2 Emission Data for the Incinerator	12
4	SO_2 Emission and Process Data for the Carbon Black Dryers	14
5	Bahco SO_2 Removal System Installations	18
6	Research-Cottrell Lime (Bahco) Scrubbing System	21
7	FMC Double Alkali Scrubbing System	24
8	Design Conditions for Phillips Petroleum's Toledo Philblack Plant for Flue Gas Desulfurization	30
9	Utility, Material, and Labor Requirements for Flue Gas Desulfurization Based on Maximum Rated Capacity Listed in Table 8	32
10	Utility, Material, and Labor Costs for Flue Gas Desulfurization at Phillips Petroleum $\$10^3$ per Year	33
11	Capital and Annualized Costs for Flue Gas Desulfurization at Phillips Petroleum, $\$10^3$, June 1976	34

ACKNOWLEDGMENTS

The assistance of Mr. Wayne E. Pearson, Project Officer, and Mr. Thomas Blaszak, U.S. Environmental Protection Agency, Air Policy Branch, Region V, Chicago, Illinois is gratefully acknowledged.

SECTION I

SUMMARY AND CONCLUSIONS

Phillips Petroleum Company's Toledo Philblack Plant would be affected by the proposed Ohio SO_2 control regulations for processes and fossil fueled-fired boilers. The plant uses a heavy oil feedstock to produce carbon black by the oil furnace process. Since the plant started operating in 1969 the sulfur content of the feedstock has risen from 0.6 percent to almost 2 percent. GCA's analyses of the potential compliance status and control measures required were based on a 2 percent sulfur feedstock.

Carbon black particles are formed by partial combustion of the feedstock oil in two parallel reactor furnaces maintained at 2800°F. Large quantities of water are used in three quench steps to stop the reaction and lower the off gas temperature for filtration. Glass fabric filters are used to filter the off gas and collect the carbon black. After collection the ultrafine carbon black particles are pelletized and dried.

Off gases containing sulfur compounds are burned in the dryers, waste heat boilers and an incinerator resulting in SO_2 emissions. The CO boilers are the largest SO_2 emission sources producing about 1900 tons per year. The proposed regulation for fossil fuel-fired steam generators, including fuels derived from fossil fuels, would require a 28 percent emission reduction. Emissions from the dryers approach 600 tons SO_2 per year requiring a 40 percent reduction during normal operation and a 47 percent reduction during peak operations. The incinerator is the smallest SO_2 source producing about 500 tons of SO_2 per year when operating at its normal rate based on a 2 percent sulfur feedstock. Incinerator

emissions would need to be reduced 2 percent during normal operation and 12 percent during peak operations.

GCA's analysis indicates that 33,000 scfm of the combined maximum flue gas flow of 93,000 scfm from all sources could be cleaned and would enable Phillips to comply with the proposed regulation. The remainder of the gas would bypass the SO_2 scrubber and be used for stack gas reheat. GCA selected the Bahco lime scrubbing system manufactured by Research-Cottrell for small industrial processes as an example control option. Capital cost of the battery limit plant was estimated to be $1.37 million. Site preparation, retrofit problems and working capital requirements raised the total capital investment to $1.92 million. Annual operating costs would be $350,000/year. Annualized cost including capital charges, depreciation, operating costs and taxes would be $580,000 per year, equivalent to $0.672 lb sulfur removed. This annualized control cost is also equivalent to 0.88 cents per pound of carbon black produced which compares to a typical carbon black selling price of 12 cents per pound.

SECTION II

PROCESS AND SITE DESCRIPTION

Phillips Petroleum Company's Toledo Philblack Plant built in 1969 produces carbon black by the oil furnace process. Mr. B. F. Ballard, director of environmental control, was contacted by GCA and EPA Region V to arrange a site visit. For several reasons a site visit was not conducted. First, Mr. Ballard felt that some of the data were confidential and requested that GCA representatives sign a secrecy agreement.[1] Second, EPA personnel from the Office of Air Quality Planning and Standards, Emission Standards and Engineering Division, Research Triangle Park, N.C. had visited the plant and collected data on several previous occasions.[2] Third, data were available from operating permit applications[3] and information submitted by Phillips during the public hearings.[4,5] Therefore, GCA used these four data sources to estimate the necessary process parameters for the subsequent evaluation of the technical feasibility and costs of complying with the proposed regulations.

Carbon black consists of particles 0.01 to 0.4 microns diameter containing 90 to 99 percent carbon. The furnace process, the thermal process and the obsolete channel process represent 95, 5 and 0.1 percent, respectively, of U.S. production capacity.[6] Both oil and gas furnace processes are used but oil furnaces represent over 90 percent of furnace process capacity. The oil furnace process used at the Toledo Philblack Plant and most other U.S. production facilities uses a liquid hydrocarbon feedstock, typically a heavy petroleum based oil such as the bottom stream from a crude catalytic cracking unit. Sulfur emissions both as H_2S and SO_2 result from the feedstock sulfur content.

The Toledo Philblack Plant has seven reactor furnaces, four in Line 1 and three in Line 2, as illustrated in Figure 1. Each production line can, depending on the type of carbon black produced, manufacture 35×10^6 pounds per year. Feedstock oil preheated to 500°F is sprayed into the reactor furnaces where it reacts with air and natural gas to maintain a furnace temperature of 2800°F. About 55 percent of the feedstock carbon content is converted to carbon black. The off gas from the reactor furnaces contains nitrogen, hydrogen, carbon monoxide, water, hydrocarbons, nitrogen oxides, sulfur dioxide and hydrogen sulfide.[5]

The type and quality of carbon black is controlled by stopping the reaction with a water quench. The prequench reduces the temperature from 2800 to 1600°F. A secondary quench is required to reduce the temperature to 1200°F. Further temperature reduction is accomplished through the air preheater, oil preheater and a third water quench which finally cools the carbon black off gas stream to 550°F. Glass fiber filter bags with an upper operating limit of 550°F are used to collect the carbon black. Reverse pressurization with filtered off gas is used to remove the carbon black from the filters for collection in the hoppers at the bottom of the filter compartment.[5]

The carbon black is pneumatically transferred from the hoppers to pelletizing mixers. Water and additives are mixed with the carbon black to form pellets. These pellets are dried in rotary dryers which are fired with process off gas. SO_2 emission from combustion of off gas in the rotary dryer would be restricted by the proposed process regulation. Flue gases from the rotary dryers vent through a single 135 foot stack before combustion.

The process off gas contains about 5 to 8 percent CO with most of the feedstock sulfur content present as H_2S. This off gas with a heating value of 30 to 50 Btu/scf is burned for heat recovery and control of CO and H_2S emissions. Operation of the two boilers would be affected

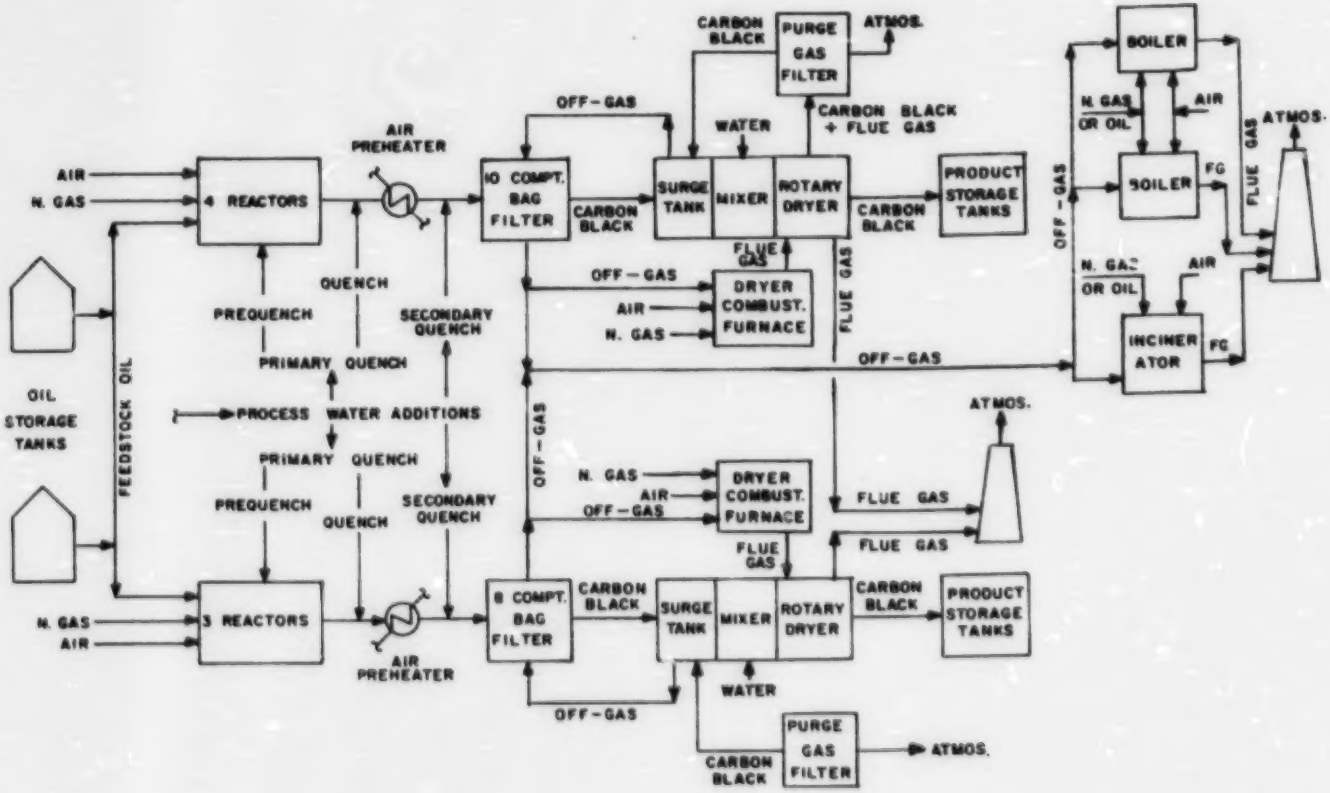


Figure 1. Phillips Petroleum Company Toledo Philblack Plant process flowsheet[5]

by the proposed regulation governing fossil fuel-fired steam generators while the incinerator would be affected by the process regulation. Flue gases from the boilers and incinerator vent through a single 135-foot stack.

CO BOILERS

The Toledo Philblack Plant uses two CO package boilers to control CO emissions and to recover energy. The fuel for the boilers is 50 to 60 percent of the off gas from the carbon black reactor furnaces. Oil is also fired in small quantities, usually less than 7 percent of the maximum, to sustain combustion. During the winter months when production is down, oil alone is fired. Each boiler has normal, rated and maximum capacities of 46.5, 64 and 69.7 x 10^6 Btu/hr, respectively. These correspond to steam productions of 30,000, 41,250 and 45,000 lb/hr. About 5 percent of the heat is used for space heat, 25 percent for process steam, and 70 percent for electric power. The boilers have no particulate or sulfur control equipment. The boilers were installed with the original plant in 1969 for the purpose of energy recovery and control of CO and H_2S emissions. The estimated remaining life of these boilers is 20 years.

The boilers are usually operated at 46.5 × 10^6 Btu/hr with most of the heat derived from off gas. At times, during the winter, oil alone is fired and then only enough to "winterize" the plant; i.e., to provide space heat and keep the process equipment hot. This corresponds to running one boiler at maximum capacity. Feedstock oil is burned in the boilers. A single 135-foot stack with a diameter of 7.5 feet services both boilers and the incinerator.

The data used to determine SO_2 emission rates were obtained from recent operating permit applications supplied to GCA by Phillips Petroleum via the U.S. Environmental Protection Agency Region V.[3] The emission

estimates were based on stack tests, material balances, emission factors and a feedstock sulfur content of 1.7 percent. A summary of these data is presented in Table 1.

Regulation §52.1881(b)(3)(iii), which applies to the two boilers (considered one for purposes of the regulation), states the following:

> " For fossil fuel-fired steam generating units between 22.5 and 3000 x 10^6 Btu/hour total rated capacity of heat input, the emission rate in lbs $SO_2/10^6$ Btu actual heat input shall be calculated by the following equation:
>
> $$E = 16.71\ Q_m^{-0.329}$$
>
> where Q_m is the total rated capacity of heat input in 10^6 Btu/hour and E is the allowable emission rate in lbs $SO_2/10^6$ Btu of actual heat input."

Fossil fuels are defined to include fuels and gases derived from fossil fuels. For the two boilers combined the total rated capacity is 128 x 10^6 Btu/hr. This corresponds to an allowable emission rate of 3.39 lbs $SO_2/10^6$ Btu actual heat input, a 15 percent reduction from the reported emission rate. However, the sulfur content of the feedstock has been increasing.

Phillips has recently received oil having close to 2 percent sulfur content. The plant originally started up with 0.6 percent sulfur oil and by 1974 this had risen to about 0.9 percent. During 1974 and 1975 the sulfur content rose even more. Phillips[4] has reported using oil containing close to 3 percent sulfur by weight in one of their Texas carbon black plants.

These high sulfur oils not only produce environmental problems but also create operational problems.[4,7] Hydrogen sulfide and moisture in the off gases create a corrosive atmosphere in the equipment. Higher sulfur content also causes lower product yield and purity.[7] The oil could be desulfurized at the expense of product yield. Desulfurization reduces

Table 1. ORIGINAL PROCESS DATA FROM OPERATING PERMITS BASED ON 1.7 PERCENT SULFUR FEEDSTOCK

	Boilers combined[a]	Incinerator	Rotary dryers each[a]
Heat input, 10^6 Btu/hr			
Normal	93	-	13.6
Rated	128	-	19.5
Maximum	139.4	-	19.5
Normal SO_2 emissions, lb/hr[b]	374.8	29.2	57.6
Normal SO_2 emissions, lb/hr[b]	400	-	-
Normal H_2S emissions, lb/hr[b]	-	32.2	-
Boiler SO_2 emissions in winter, lb/hr[c]	15.6	-	-
Normal off gas burned, scf/hr	1,715,200		278,600
Stack gas flow rate, acfm	97,450		15,020
Stack gas temperature, °F	575		700
Off gas molecular weight[5]	24.1		

[a] There are two dryers; data represent individual dryers.

[b] Stack test data based on 1.7 percent sulfur oil.

[c] Data represent combustion of oil alone, GCA estimates 128 lb/hr.

the aromatic content[5] of the oil, which determines yield. Thus, more oil must be charged to obtain an equivalent product rate.

Emission rates based on 2 percent sulfur oil that may be used in the near future are presented in Table 2. The emission rates in Table 2 were used by GCA as the basis for control equipment estimates. Based on the proposed regulation previously discussed SO_2 emissions from the CO boilers would need to be reduced 28 percent to 3.39 lb $SO_2/10^6$ Btu either by flue gas desulfurization or by obtaining a feedstock with 1.43 percent sulfur. When the boiler is fired by feedstock oil only it would comply with the proposed regulation.

INCINERATOR

The incinerator burns off gas which is in excess of that required in the boilers and dryers. It is mainly used to control CO emissions. Normally, 0 to 15 percent of the total off gas produced is burned in the incinerator. The unit is not currently operating as per a variance issued by the Toledo Pollution Control Agency. Excess off gas is, therefore, simply vented through the incinerator and stack. The proposed process regulation only affects SO_2 emissions, so if the incinerator is not operated it may not be affected. Although the gases pass through the same stack as the boiler, a different regulation applies when the incinerator is in operation.

The incinerator falls under the process regulation stated in §52.1881(b)(8):

> "..., no owner or operator of any process equipment shall cause or permit the emission into the atmosphere of any process gas stream containing sulfur dioxide in excess of the amount prescribed by the following equation:
>
> $$E = 19.5\ p^{0.67}$$

Table 2. SO_2 EMISSION DATA FOR THE CO BOILERS[a]

	Normal operation	Maximum rated
Heat input, 10^6 Btu/hr	93	128
SO_2 emission rate,[b] lb/10^6 Btu	4.73	4.73
SO_2 emission rate,[b] lb/hr	441	606
Allowable SO_2 emission rate, lb/10^6 Btu	3.39	3.39
Emission reduction required, percent	28.4	28.4
lb SO_2/hr	126	171
Flue gas flow,[c] acfm	90,450	124,000
Flue gas flow,[c] scfm	46,900	64,300
Flue gas temperature, ^oF	575	575
Excess air, percent	16	16
SO_2 concentration in flue gas, ppm	900	900

[a]Data are combined totals for both boilers, based on a 2 percent sulfur feedstock.

[b]When the process is shut down for short periods during the winter, feedstock oil is fired alone in the boiler. The emission rate would be 2.1 lb SO_2/10^6 Btu.

[c]30 to 40 percent moisture.

where E is the allowable emission rate in lbs SO_2/hour
and p is the tons of process weight per hour."

For the incinerator the tons/hour of gas burned is the process weight. To determine the level of reduction required to bring the incinerator into compliance it was assumed that all sulfur in the gas leaving the incinerator was SO_2. At present only about one third of the sulfur by weight exits as SO_2, the remainder being H_2S. The actual and allowable SO_2 emission rates when 2 percent sulfur feedstock is used are presented in Table 3.

The incinerator needs no reduction if excess off gas is simply vented as the emissions would be H_2S not SO_2. If it were put back into operation it would require a 2.2 percent reduction under normal load and 11.8 percent at maximum load. A system which could handle the incinerator flue gas by itself under operating and nonoperating conditions would be economically impractical. When used as a vent, the incinerator exhausts gases containing CO, volatiles, tars, and, at times, particulates. Thus, if the FGD system had no pretreaters, similar to a by-product recovery plant at a coke making operation, these constituents would be removed in the prescrubber or scrubber of an FGD system causing increased operating costs, possible corrosion problems, and potential disposal problems. A more practical approach is to let the incinerator vent into the stack directly and remove the required amount of SO_2 from the boiler flue gases such that the total SO_2 emitted from the stack is less than the combined allowable emissions from the boilers and the incinerator. This would require reductions of 29.1 and 31.3 percent for the boilers under normal and maximum operating rates, respectively.

Dryers

The plant has two dryers which in conjunction with surge tanks and mixers turn the carbon black produced in the furnaces into a saleable product. Carbon black particles are mixed with water, usually in the

Table 3. SO_2 EMISSION DATA FOR THE INCINERATOR[a]

	Normal operation	Maximum rated
Process weight,[b] ton/hr	12.95	17.9
SO_2 emission rate,[c] lb/hr	110	152
Allowable SO_2 emission rate, lb/hr	108	134
Emission reduction required, percent	2	12
SO_2 removal required, lb/hr	2	18
Flue gas flow,[d] acfm	22,900	31,600
Flue gas flow,[d] scfm	6,200	8,200
Flue gas temperature, °F	1,600	1,600
SO_2 concentration in flue gas,[a] ppm	1,700	1,700

[a]Based on a 2 percent sulfur feedstock.

[b]GCA estimate.

[c]SO_2 equivalent. When incinerator is not operating, sulfur emissions are reported to be 1/3 SO_2, 2/3 H_2S by weight.

[d]30 to 40 percent water.

ratio of 2 lb carbon black to 1 lb water and then dried in the rotary dryers. This process forms a spherical particle of larger size than the original particles. Material handling and shipping is thus simplified.

Each dryer has its own combustion furnace which supplies both direct and indirect heat to the carbon black-water mix. Off gases from the carbon black furnaces are used with oil or natural gas to fire the rotary dryers. About 90 percent of the effluent gases are used to fire the dryers indirectly. The remaining 10 percent is sent directly to the wet carbon black to drive off residual moisture. The resulting wet gas stream is vented through a filter which captures carbon black particles. The main component; i.e., that which is indirectly fired, is vented through a 135 foot high, 3 foot diameter stack.

The proposed regulation applicable to the dryers, considered separately, is the process regulation §52.1881(b)(8). The allowable emission rate for SO_2 is:

$$E = 19.5\ p^{0.67}$$

where E is the allowable emission rate in lb SO_2/hour and p is the tons of process weight per hour. The process weight for the dryers is the sum of the carbon black charged and the water added in the mixer. The data used to determine the levels of SO_2 emissions from the dryers were taken from the permits supplied to GCA via EPA Region V and were presented in Table 1. The production rate of carbon black per line was determined assuming an 85 percent carbon content in the oil, a product yield of 55 percent based on the oil carbon content and a sulfur balance.

The pertinent SO_2 emission and process data are presented in Table 4. The dryers under maximum operating rates (scaled up on the basis of

Table 4. SO_2 EMISSION AND PROCESS DATA FOR THE CARBON BLACK DRYERS[a]

	Normal operation, dryer No. 1[b]	Maximum rated, dryer No. 1[b]
Process weight,[c] ton/hr	3.00	4.30
SO_2 emission rate, lb/hr	67.8	97.2
Allowable SO_2 emission rate, lb/hr	40.7	51.9
Emission reduction required, percent	40.0	46.6
SO_2 removal required, lb/hr	27.1	45.3
Flue gas flow,[d] acfm	15,000	21,600
Flue gas flow,[d] scfm	6,940	10,000
Flue gas temperature, ^oF	700	700
SO_2 concentration in flue gas, ppm	900	900

[a]Based on a 2 percent sulfur feedstock.

[b]Dryer No. 1 and Dryer No. 2 are identical. Total emissions from drying are twice those listed above.

[c]Carbon black and water charged to the mixer. About 1 part water to 2 part carbon black. Calculated based on 2 percent sulfur feedstock, 343.5 lb/hr total S emissions from all sources, 55 percent yield from feedstock carbon content and 85 percent carbon in the feedstock.

[d]30 to 40 percent water.

maximum and normal heat inputs) require an emission reduction of 46.6 percent. The information submitted to GCA via EPA Region V by B. F. Ballard, Director of Environmental Control, Phillips Petroleum[4] indicated that each dryer has its own stack. Public comment statements made by Phillips, a trip report by PEDCO - Environmental, and K. C. Hustvedt (USEPA) indicated that the dryers exhaust into a single stack. Even though this discrepancy exists, it does not alter the allowable emissions. Duplicate or similar parallel operation must be within a structure, building or shop to be considered as a single source.

Under normal operating conditions the regulations would be met if the equivalent of 1.2 percent sulfur oil was burned in the dryers or if flue gas desulfurization was used.

SECTION III

SO_2 CONTROL TECHNOLOGY

FLUE GAS DESULFURIZATION

A flue gas desulfurization system designed to clean 33,000 acfm at a 90 percent SO_2 collection efficiency would enable Phillips Petroleum Toledo Philblack to comply with the proposed regulation when using 2 percent sulfur feedstock. Inlet SO_2 concentration would be about 900 ppm and the outlet would be 90 ppm. Particulate concentration entering the scrubber would be insignificant; i.e., less than 0.05 gr/scf. The above flue gas flow rate, SO_2 collection efficiency, SO_2 concentration and particulate concentration are within the ranges of flue gas desulfurization systems operating on oil- and coal-fired boilers.

There are many flue gas desulfurization processes either currently in use or under development for control of SO_2 emissions from boilers. These methods include wet scrubbing with lime, limestone, magnesium oxide, sodium sulfite (Wellman-Lord), sodium hydroxide (double alkali) and sodium citrate. Catalytic oxidation, dry adsorption on carbonaceous materials, absorption by molten carbonate and other processes are also being developed. Many of these processes are not applicable to small industrial boilers or processes due to the poor economics of small scale systems. GCA has selected the Bahco system, a wet scrubbing process using lime,

manufactured by Research-Cottrell* and the FMC+ double alkali system for evaluation in this study. These two systems were selected because they are specifically designed and marketed for application to industrial boilers and processes and because the technology has been successfully demonstrated.

Lime Scrubbing

Lime scrubbing systems are manufactured by numerous engineering construction firms and have been in use on utility boilers for several years. Although lime scrubbing is very similar to limestone scrubbing there are several potential advantages of using lime particularly for smaller systems. Raw material transport costs are lower, maintenance and scaling may be reduced, raw material utilization is more effective, and solid waste quantities are slightly lower. Twenty lime scrubbing systems designed to clean 16,000,000 scfm of flue gas are operating under construction or committed to construction on large boilers in the U.S.[8]

Although the Bahco system currently being marketed by Research-Cottrell uses lime as the adsorbent, the same scrubber has been used with other adsorbents. Table 5 illustrates the commercial application of Bahco scrubbers to small boilers and process sources. This table indicates the Bahco system is a technically feasible SO_2 scrubbing system, but it is recognized that the economic feasibility varies with the source type and may be different in the U.S. The cost of SO_2 control is discussed in Section IV.

The Research-Cottrell Bahco-lime scrubbing system (see Figure 2) consists of a two-stage venturi. The first venturi presaturates the gas, removes

---

*Research-Cottrell
P.O. Box 750
Bound Brook, N.J.

+FMC Corporation
Environmental Equipment Division
Westport, Conn.

Table 5. BAHCO SO_2 REMOVAL SYSTEM INSTALLATIONS[9]

Company	Location	Number of units	Unit capacity scfm @ 77°F	Service	Scrubbing reagent	Inlet SO_2 concentration	SO_2 removal efficiency %	On-line
Sodersjukhuset	Stockholm, Sweden	3	19,300	Oil-fired boiler	$Ca(OH)_2$	800 - 1500 ppm	97 - 99	Nov. 1969, April. 1970
Daishowa Seishi Company	Suzukawa, Japan	1	16,000	Oil-fired boiler	NaOH	900 - 1200 ppm	97 - 99	Jul. 1970
Daishowa Seishi Company	Yoshinaga, Japan	5	48,200	Oil-fired boiler	NaOH	900 - 1000 ppm	97.5	Aug. 3, 1970/ Jul. 2, 1972
Osaka City	Osaka, Japan	1	11,000	Secondary sludge incinerator	NaOH	70 - 80 ppm	50[a]	Mar. 1971
Hiroshima City	Hiroshima, Japan	1	11,000	Secondary sludge incinerator	NaOH			Dec. 1970
Yahagi Iron Works	Nagoya, Japan	1	53,000	Sintering Plant	$Ca(OH)_2$ Waste Carbide Sludge	2500 - 4000 ppm	90 - 95	Dec. 1970
Taio Paper Company	Iyomishima, Japan	1	90,600	Oil-fired boiler	NaOH	1000 - 1500 ppm	98	Jan. 1971
		1	72,500	Oil-fired boiler	NaOH	1000 - 1500 ppm	98	Jan. 1971
Central Glass Company	Sakai, Japan	1	34,200	Glass furnace	NaOH	1200 ppm (25% SO_3)	98	Mar. 1971
Stora Kopparberg	Gryckbo, Sweden	1	19,300	Black liquor boiler	CaO and $CaCO_3$ dust	4000 - 6000 ppm	70[a]	Sept. 1972
Kanegafuchi Chemical	Takasago City, Japan	2	173,000	Oil-fired boiler	NaOH	1400 - 1530 ppm	95 - 98	Apr. 1973
Kino Ura Utility	Japan	1	81,900	Oil-fired boiler	NaOH	1500 ppm		Sept. 1974
Rickenbacker Air Force Base	Colmbus, Ohio	1	54.500	Coal-fired boiler	CaO	4000 ppm	90[a]	Feb. 1976

[a]Sufficient to meet local code.

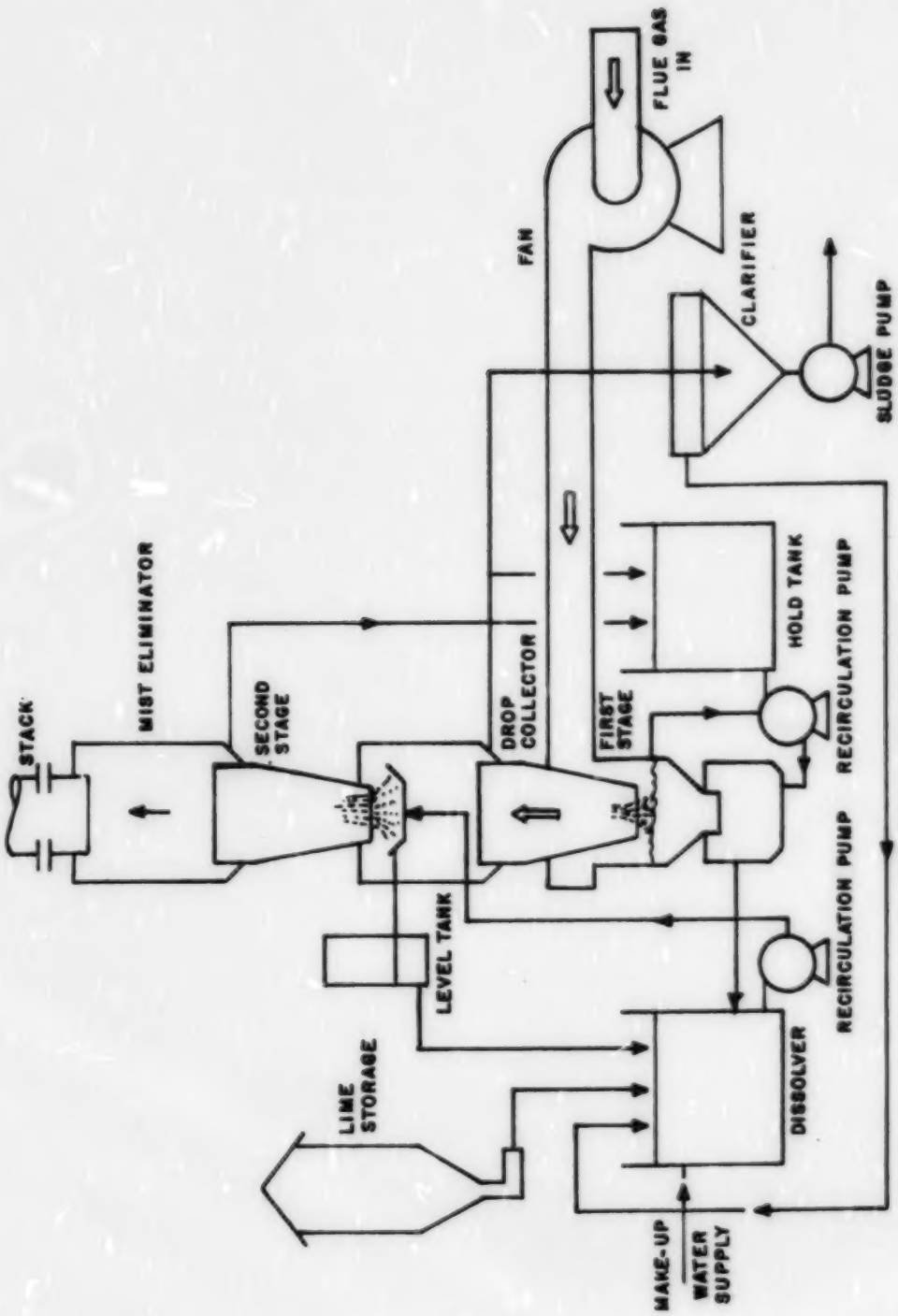


Figure 2. R-C Lime (Bahco) scrubber system[10]

some SO_2 and may be designed to remove particulates. At the bottom of the column, flue gas is directed down against the surface of a milk lime slurry. The high velocity gas-liquid contact produces a vigorous cascade of droplets that carry up into the first scrubber stage for turbulent mixing with the flue gas. Above the first venturi, droplets are separated in an inertial collector while the gas continues up to a second stage where the gas-liquid contact process is repeated. A mist eliminator above the second stage frees the gas of droplets prior to exiting out the stack. Separated liquids from both stages of the venturi return to the lower impingement zone. A fraction of this return flow is continuously removed for disposal, usually to a thickener. Clarified liquid is returned to the lime dissolving tank to minimize makeup requirements.[10] Operating and design characteristics of the Bahco system are summarized in Table 6.

Double Alkali Scrubber Systems

A double alkali scrubber system has been developed by FMC Corporation and is currently in operation and being marketed commercially. The process involves a sodium-based scrubbing loop in which the sulfur dioxide in flue gas is collected according to the following reactions:

$$Na_2CO_3 + H_2O \rightarrow 2NaOH + CO_2$$

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

and subsequently precipitated with calcium in a separate loop according to the reaction

$$2NaHSO_3 + Ca(OH)_2 \rightarrow CaSO_3 + Na_2SO_3 + 2H_2O)$$

Table 6. RESEARCH-COTTRELL LIME (BAHCO) SCRUBBING SYSTEM[11]

Smalles system capacity commercialyy available (scfm)	20,000
Overall pressure drop through system (in H_2O)	16 - 26
Turndown ratio of system[a]	1.5 - 1
SO_2 removal efficiency, percent	90 - 99
Raw materials	Lime
By-products	None
Wastes[b] lb waste/lb SO_2 removed	6.1 lb cake containing 35 percent solids ($CaSO_3$ and $CaSO_4$) and 65 percent water
Maintenance	Scaling and solids deposition appear to be less severe than for limestone based scrubbing systems. Corrosion can be minimized by properly designing the system.
Development status (see Table 5)	Operational systems in the United States 55,000 scfm 3.6 % S coal

[a]Any turndown ratio may be accomodated by the addition of makeup air.

[b]Does not include the fly ash that would be removed.

This system was developed primarily to alleviate scaling problems initially encountered with lime/limestone systems. The spent scrubber solution which is primarily composed of sodium bisulfite ($NaHSO_3$) is pumped to a lime reactor where it mixed with slaked lime. In the reactor. sodium bisulfite is converted to sodium sulfite (Na_2SO_3) and calcium sulfite ($CaSO_3$) is precipitated out, thickened and put through a rotary drum vacuum filter. The sodium sulfite solution is then recirculated back to the scrubber. Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to become sodium sulfate. These chemical losses are offset with makeup soda ash.[12] A schematic of FMC's double alkali scrubber system is presented in Figure 3. Table 7 presents pertinent design and operating data for the FMC double alkali scrubbing system.

Sludge Disposal

Nonregenerative scrubbing systems for SO_2 control produce sludges that must be utilized or disposed. Sludges produced by lime and limestone SO_2 scrubbing systems contain primarily calcium sulfite, calcium sulfate, calcium carbonate and fly ash. At Phillips the fly ash and trace metal components will be insignificant. Water content is typically 50 to 80 percent. An environmentally acceptable method for sludge disposal or utilization must be considered in the evaluation of the technical feasibility and cost of scrubbing. Numerous options have been proposed for sludge utilization[14,15] but significant application of these techniques especially to small systems appears to be unlikely. A recent EPA sponsored study concluded that ponding and landfill are the only near term alternatives for sludge disposal.[16]

In order to assess this problem it is useful to compare the properties of scrubber sludge to fly ash. First, sludge tends to be more difficult to dewater either by settling or filtration and rewaters more easily. The platelet-like crystal structure of calcium sulfite hemihydrate ($CaSO_3$-1/2 H_2O) is believed to be primarily responsible for the high

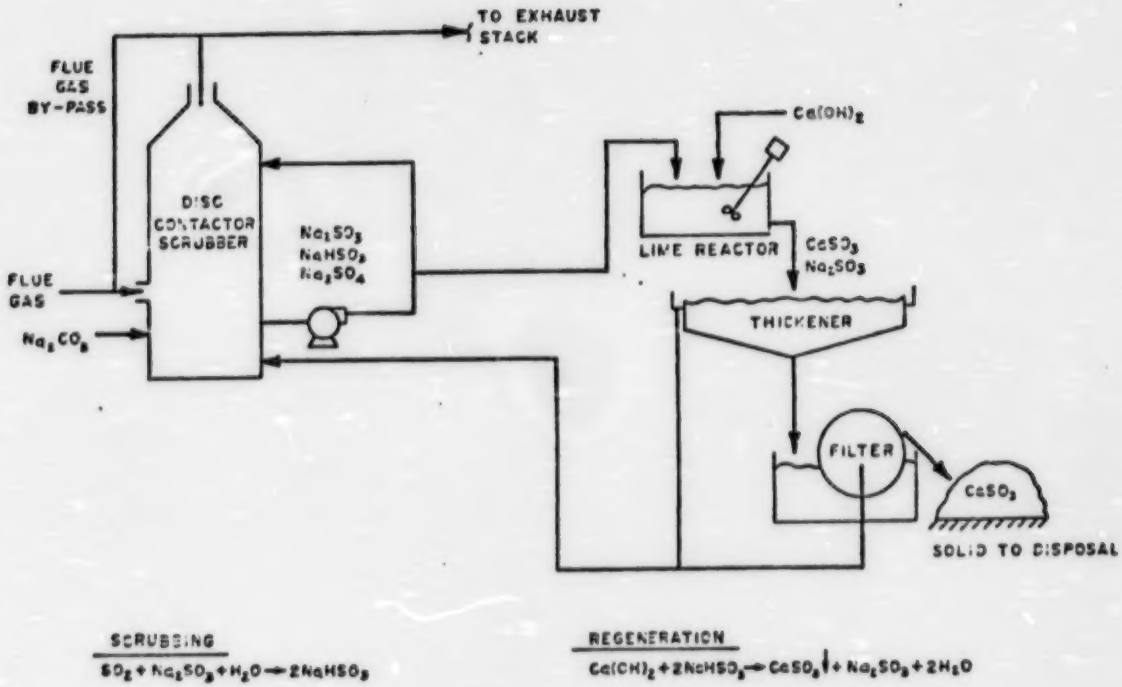


Figure 3. FMC double alkali scrubber system[12]

Table 7. FMC DOUBLE ALKALI SCRUBBING SYSTEM[13]

Smallest system capacity commercially available (scfm)	33,000
Overall pressure drop through system (in H_2O)	5 - 15
Turndown ratio of system	4:1
SO_2 removal efficiency, percent	90 - 95
Raw materials	Lime (CaO), soda ash (Na_2CO_3)
By-products	None
Wastes[a] lb waste/lb SO_2 removed	5.8 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$ and Na_2SO_4) and 65 percent water
Maintenance	This system is designed so that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	Operational systems 3 MW; 2 % S coal; 90 % SO_2 removed 94 % availability; operating since 1/75. 3 MW; 3.2 % S coal; 90 % SO_2 removal 100 % availability; operating since 10/75. Systems in engineering design and construction phase of development. 95 MW; 3.2 % S coal; startup slated for 1977. 93 MW; 3.2 % S coal; startup slated for 1978

[a]Does not include the fly ash that would be removed.

moisture retention.[17] Depending on the sludge composition including the amount of fly ash it will settle to 30 to 65 percent solids compared to fly ash which settles to 80 percent solids. Dewatering problems lead to increased processing costs, larger ponding areas and poorer landfill characteristics. Untreated sludge liquors have a lower pH than fly ash liquors thus causing greater trace metal solubility.[18] Wet scrubbing may also collect gaseous trace elements including chlorine and mercury, increasing the water pollution potential. Problems with trace metals from oil-derived flue gas at Phillips will be insiginficant.

Ponding is currently the most commonly used lime/limestone sludge disposal method. All wet scrubbing systems present the potential problem of direct waste water discharge to surface waters. Eight full scale systems representing over 1500 mW of boiler capacity have eliminated this problem by recirculating the scrubber liquor; i.e., closed loop operation.[19] Other installations recirculate as much of the liquor as technically feasible. Pollution of ground and surface waters from leachate formation is also a potential problem. Ponds may be lined with clay or synthetic materials like asphalt, PVC, Hypalon, etc.[20] The necessity for lining and/or stabilization depends on local regulations, sludge characteristics and local geology and hydrology. Currently, only Commonwealth Edison, Will County No. 1, is using a lined (clay) pond[8] but future requirements will probably be more stringent.

Costs for sludge disposal by ponding can vary very widely, depending on land cost; the type of liner used, if any; location of the pond in relation to the scrubbers; and the settling characteristics of the sludge. The need for a pond liner and the type used and therefore the disposal cost will depend on local geology, hydrology and environmental regulations. It has been suggested that the small size of some industrial boilers may reduce the sludge disposal problem as local environmental impacts will be reduced.[21] Only 3400 tons/year of sludge containing 50 percent solids

would be generated at Phillips and impacts of disposal should be less severe when compared to the 700,000 tons of sludge that would be produced by a typical utility boiler. Aerospace Corporation has conducted a detailed evaluation of ponding[20] and is currently continuing programs in the area. Data from this initial study have been updated and cost ranges are $0.2 to $3 per ton of sludge (50 percent solids) for unlined pond disposal and $0.5 to $10 per ton of sludge for lined pond disposal.[16] The large range and higher upper limits reflect uncertainty in regard to unusual local situations. A cost of $3 per ton for sludge disposal in a lined pond was reported to be typical. Costs would be nearer $1 per ton if disposal in an unlined pond is allowed. Typical truck hauling rates for stabilized fly ash for a distance of 5 miles are reported to be $0.75/ton.[16] This may represent an added cost when offsite ponding or landfill is required. Based on the above data, GCA used a cost of $4/ton for sludge disposal.

Landfill is also a viable disposal method although use of this option is currently limited. Dewatering and sludge stabilization or chemical fixation are usually required for landfills. Chemical fixation and landfillin is reported to cost more than ponding in most situations, averaging about twice as much. A specific example of chemical fixation and landfill is the Bruce Mansfield No. 1 unit, a 835 mW system. Projected costs are reported to be $7/ton of sludge including Dravo chemical fixation, acquisition and development of considerable land, and an 8-mile pipeline operation.[20] However, it may be feasible to simply mix the small quantities of sludge from Phillips with larger quantities of municipal wastes in a local sanitary landfill. Sophisticated chemical fixation would probably not be needed.

Sludge from sodium-based double alkali systems have been less intensively investigated. A major difference between sludges from lime/limestone systems and double alkali systems is that the former are primarily calcium sulfate ($CaSO_4$) while the latter are primarily calcium sulfite

($CaSO_3$). One might expect, in view of the dewatering problems attributed to minor amounts of $CaSO_3$ in lime/limestone sludge, that double alkali sludge would be difficult to dewater. However, FMC has investigated vacuum filtration and landfilling of double alkali sludge and reports success in both areas.[12] Perhaps the different conditions under which the sludges form also affects the properties.

While sludge disposal is an important environmental consideration, disposal methods are available and the annual cost should be relatively small, less than 10 percent of the total annual FGD cost.

Low Sulfur Feedstock

An obvious alternative that would enable Phillips Petroleum's Toledo Philblack Plant to comply with the proposed regulations would be to use a 1.2 percent sulfur feedstock. When the Phillips carbon black plant started production in 1969 the feedsotck oil contained 0.6 percent sulfur.[4] During 1973 the feedstock contained 0.9 percent sulfur and late in 1975 feedstock delivered to the plant contained as much as 2 percent sulfur.[4] Phillips purchases its feedstock from other companies and reports that they have virtually no control over the sulfur content of the feedstock.[4]

The ideal raw material for carbon black production is a highly aromatic, low sulfur, high molecular weight, resin or asphaltene containing substantially no suspended ash, carbon or water.[22] Cracked fuel oil by-products are commonly used as feedstock but by-products from the production of ethylene might also be used.[23] The yield of carbon is generally correlated with the aromaticity of the feedstock (typically 65 to 85 percent) and the Bureau of Mines Correlation Index, an indication of feedstock suitability. However, actual yield can only be determined from plant or pilot plant tests.[22]

Sulfur in the feedstock is undesirable for several reasons in addition to the air pollution potential. It increases the corrosive nature of the off gases, thus reduce the life of the bag filters, process equipment blowers, compressors, etc. In addition, the yield of carbon black per pound of feedstock decreases.[4]

Desulfurization of feedstock oil may not be feasible as the aromatic content of the oil is reduced. Therefore, the product yield is reduced. Phillips reports that the magnitude of the reduction in product yield would make this option unacceptable. In any case it may not be possible for Phillips to obtain a desulfurized feedstock.

SECTION IV

COST OF SO_2 CONTROL

There are two alternatives for Phillips Petroleum to bring the Toledo Philblack Plant into compliance with the proposed regulation. First, compliance could be achieved by using a 1.2 percent sulfur feedstock. If such a feedstock could be obtained without desulfurization, the cost would probably be higher than the present feedstock. The cost of a lower sulfur feedstock would need to be balanced against decreased equipment corrosion, increased product yield and better product purity. Similar benefits would result from using a desulfurized oil except that yield would decrease because of a decreased aromatic content. The second alternative is flue gas desulfurization. The cost of this second option is discussed in this section.

The design conditions for flue gas desulfurization are summarized in Table 8. At maximum rated capacity the required reduction in SO_2 emissions can be accomplished by removing 90 percent of the SO_2 contained in 33,000 scfm of flue gas from the boilers and dryers. The remainder of the flue gas from the boilers, incinerators and dryer will bypass the scrubber and be used for reheat. All gases will vent through a single stack. System capacity would be based on the maximum rated capacity but utility and material consumption would be based on the normal operating rate and the reported 8150 hours of operation per year.

The Bahco lime scrubbing system designed for small flue gas flows and manufactured by Research-Cottrell was selected for cost analysis. Bahco process details were presented in the previous section. Research-

Table 8. DESIGN CONDITIONS FOR PHILLIPS PETROLEUM'S TOLEDO PHILBLACK PLANT FOR FLUE GAS DESULFURIZATION[a]

	Normal operation				Maximum rated			
	Both boilers	Incin-erator	Both dryers	Total	Both boilers	Incin-erator	Both dryers	Total
SO_2 emission rate, lb/hr	441	110	136	687	606	152	194	952
Allowable SO_2 emission rate, lb/hr	315	108	81	504	435	134	104	673
Emission reduction required, lb/hr	126	2	55	183	171	18	90	279
Flue gas flow,[b] scfm	46,700	6,200	13,900	66,800	64,300	8,200	20,000	93,200
Flue gas temperature, ^oF	575	1,600	700	≈ 600	575	1,600	700	≈ 600
Flue gas to be treated, scfm				21,500[c]				32,800[c]
Treatment efficiency, percent				90				90
SO_2 collected, lb/hr				183				279

[a]Based on a 2 percent sulfur feedstock and data developed in Tables 2, 3, and 4.

[b]30 to 40 percent moisture.

[c]Remainder of the gas volume including the entire incinerator flow; would be bypassed to provide reheat.

Cottrell recently provided cost estimates to GCA for a 30,000 scfm, 90 percent efficient system for a coal-fired boiler.[24] These cost data were modified by GCA to reflect the flue gas properties and flow rates at Phillips Petroleum's Toledo Philblack Plant.

Utility, material and labor requirements are summarized in Table 9. Power and process water requirements were increased 10 percent to reflect the 10 percent greater flue gas volume. These increases are attributable to greater energy consumption for the system fan and larger water losses by evaporation and sludge disposal. Lime consumption is based on the SO_2 removed and a lime utilization efficiency of 95 percent. Maintenance costs were difficult to accurately determine. Battelle has used 1.5 percent of fixed capital investment for maintenance materials and 1.5 percent for labor for a Bahco system applied to a coal-fired boiler.[21] Research-Cottrell reported total maintenance costs of 3 percent[24] and TVA has reported costs of maintenance as 7 to 9 percent of direct investment for FGD applied to large boilers. GCA has used a relatively high maintenance cost of 3.5 percent of fixed capital investment for materials and an equivalent cost for maintenance labor. Research-Cottrell reported that 0.25 men/shift were required to operate the system but GCA again used a more conservative estimate of 0.5 men/shift.

The detailed costs for utility, material, and labor are listed in Table 10. Maintenance is the largest single cost component. Total utility, material and labor costs were calculated to be $226,000/year based on an average yearly load factor of 70 percent.

Capital and annualized control costs are presented in Table 11. The battery limit plant cost is based on an estimate for a similar system (10 percent less gas volume) provided by Research-Cottrell. Site preparation costs including service facilities, the cost of utility connections, and the cost of normal flue gas ducts were estimated to be 20 percent of the battery limit plant cost. Because space between the boilers and stack is restricted and additional ducting would be needed to

Table 9. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION BASED ON MAXIMUM RATED CAPACITY LISTED IN TABLE 8

	Bahco Lime scrubbing
Utility	
Power, kWh/day	4,930
Process water, 1000 gal/day	33
Material	
Lime (CaO) tons/day	3.09
Maintenance, percentage of fixed capital investment/year	3.5
Labor	
Operation, men/shift	0.50
Maintenance, percentage of fixed capital investment/year	3.5

Table 10. UTILITY, MATERIAL, AND LABOR COSTS FOR FLUE GAS DESULFURIZATION AT PHILLIPS PETROLEUM 10^3 PER YEAR[a]

	Bahco Lime scrubbing
Utility	
Power, $0.02/kWh	25.3
Process water, $0.20/1000 gal	1.7
Total utilities	27.0
Material	
Lime (CaO) $40/ton	31.5
Maintenance	64.8
Total material	96.3
Labor	
Operation $8/man-hr	35.0
Maintenance	64.8
Total labor	99.8
Total utility, material, and labor	223.1

[a]Utility and lime consumption are based on an average operating load of 75 percent over 8,150 hr/year, equivalent to an average yearly load factor of 70 percent.

Table 11. CAPITAL AND ANNUALIZED COSTS FOR FLUE GAS DESULFURIZATION AT PHILLIPS PETROLEUM, 10^3, JUNE 1976

	Lime scrubbing (BAHCO System - Research-Cottrell)
Capital requirement	
Battery limits plant installed[a] (BLP)	1,370
Site preparation and utilities,[b] 20% of (BLP)	274
Additional retrofit requirements, 15% of (BLP)	206
Fixed capital requirement	1,850
Working capital,[c] 20% of gross operating cost	70
Total capital requirement	1,920
Annual operating cost	
Labor[d]	99.3
Administrative and general overhead,[c] 60% of labor	59.6
Utilities[d]	27.0
Materials[d]	96.3
Local taxes and insurrance,[c] 2.7% of fixed capital requirement	50.0
Solid waste disposal, $4/ton	15.3
Gross operating cost	347.5
Total annual operating cost	347.5
Annualized cost	
Annualized capital cost[e]	195.6
Federal income tax[c,f]	34.4
Total annual operating cost	347.5
Average annual cost	577.5
Average annual control cost $/lb S removed	0.672
Average annual control cost, ¢/lb carbon black produced	0.879

[a] Scaled up from manufacturers estimate of $1,300,000 for a 30,000 scfm system applied to a coal-fired boiler on the basis of gas flow to the 0.6 power. June 1976.

[b] Normal site preparation cost to bring utilities to the battery limit plant and connect inlet ducts to battery limit plant based on GCA review of similar costs reported in the literature.

[c] Based on utility financing method as modified by the Panhandle Eastern Pipeline Company and described in Reference 21.

[d] See Tables 9 and 10.

[e] Total capital requirement is amortized over 20 years based on discount cash flow rate of 8 percent. This works out to an effective annualized capital cost of 10.185 percent per year of the total capital requirement.

[f] Average federal income tax = 1.731 percent of the sum of the total capital requirement and working capital.

connect all the flue gas streams an additional retrofity cost of 15 percent of the battery limit plant cost was included. The total capital investment for this 33,000 scfm system was estimated to be $1.9 million. Average annual control cost including annualized capital cost (based on a discounted cash flow rate of 8 percent), federal income tax, and annual operating cost was $580,000/year. This final annual cost is equivalent to $0.672 per pound of sulfur removed or 0.88 cents per pound of carbon black produced. This cost can be compared to the average current price for carbon black of 12 cents per pound.

SECTION V

REFERENCES

1. Ballard, B. F. Phillips Petroleum Company letter to R. R. Hall, GCA/Technology Division. April 20, 1976.

2. Personal Communication with K. C. Hustvedt, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Emission Standards and Engineering Division, Research Triangle Park, N.C. May 1976.

3. Copies of Operating Permit Applications submitted by B. F. Ballard, Phillips Petroleum Company, to T. Blaszak, Air Policy Branch, Air and Hazardous Materials Division, U.S. Environmental Protection Agency Region V. May 13, 1976.

4. Ballard, B. F. Phillips Petroleum Company letter to J. A. Chicca, U.S. Environmental Protection Agency Region V. Public Comment No. 198. January 23, 1976.

5. Ballard, B. F. Phillips Petroleum Company letter to L. Borsamian, U.S. Environmental Protection Agency Region V. Public Exhibit 91. December 31, 1975.

6. Energy Crunch Still Hurting Carbon Black. Chemical and Engineering News. April 5, 1976.

7. Briggs, T. and J. Richards. Trip Report: Phillips Petroleum Company, Toledo, Ohio, Toledo Philblack Plant - PEDCo - Environmental. Cincinnati, Ohio. August 1974.

8. Summary Report, Flue Gas Desulfurization Systems. PEDCo - Environmental Specialists, Inc., Cincinnati, Ohio. March - April 1976.

9. Research-Cottrell/Bahco SO_2/Particulate System for the Pulp and Paper Industry. Technical Bulletin 201. Research-Cottrell, Bound Brook, N.J.

10. The Research-Cottrell Bahco Process. Bulletin RC 1100.

11. Site Visit by GCA. Rickenbacker Air Force Base, Columbus, Ohio. April 1976.

12. Legartski, L. Carlo, K. E. Johnson, and L. Y. Lee. FMC Concentrated Double-Alkali Process. (Presented at the Flue Gas Desulfurization Symposium. New Orleans, Louisiana. March 8-11, 1976.)

13. Personal Communications with John Makar. FMC Corporation. May 1976.

14. Proceedings: Symposium on Flue Gas Desulfurization - Atlanta, November 1974. U.S. Environmental Protection Agency. EPA-650/2-74-136b. Research Triangle Park, N. C. December 1974.

15. Taylor, W. C. and J. C. Haas. Potential Uses of the By-Product From the Lime/Limestone Scrubbing of SO_2 From Flue Gases. (Presented at the American Institute of Mining, Metallurgical and Petroleum Engineers 1974 Annual Meeting. Dallas, Texas. February 1974.)

16. Princiotta, F. T. Sulfur Oxide Throwaway Sludge Evaluation Panel (SOTSEP). Volume II: Technical Discussion. U.S. Environmental Protection Agency. EPA-650/2-75-010b. Research Triangle Park, N.C. April 1975.

17. Jones, J. W. Environmentally Acceptable Disposal of Flue Gas Desulfurization Sludges: The EPA Research and Development Program. (Presented at the Symposium on Flue Gas Desulfurization. Atlanta, Georgia. November 1974.)

18. Air Quality and Stationary Source Emission Control. Report by Commission on Natural Resources. National Academy of Sciences. March 1975.

19. Ifeadi, C. M. and H. S. Rosenberg. Lime/Limestone Sludge Disposal - Trends in the Utility Industry. (Presented at the Symposium on Flue Gas Desulfurization. Atlanta, Georgia. November 1974.)

20. Rosoff, J. and R. C. Ross. Disposal of By-Products From Non-Regenerable Flue Gas Desulfurization Systems: Initial Report. The Aerospace Corporation. U.S. Environmental Protection Agency. EPA 650/2-74-037a. Research Triangle Park, N.C. May 1974.

21. Choi, P. S. K. et al. SO_2 Reduction in Nonutility Combustion Sources, Technical and Economic Comparison of Alternatives. Battelle-Columbus Laboratories. U.S. Environmental Protection Agency. EPA-600/2-75-073. Research Triangle Park, N. C. October 1975.

22. Schwartz, W. A., et al. Engineering and Cost Study of Air Pollution Control for the Petrochemical Industry, Volume I. Carbon Black Manufacture by the Furnace Process. Air Products and Chemicals, Inc. U.S. Environmental Protection Agency. EPA-450/3-73-006a, Research Triangle Park, N. C. June 1974.

23. Stokes, C. A. Carbon Black. Encyclopedia of Chemical Technology Supplement Volume, 2nd Edition. John Wiley and Sons, Inc. 1971

24. Research-Cottrell Cost Estimate provided by Jim McCarthy. June 1976.

25. McGlamery, G. G., et al. Detailed Cost Estimates for Advanced Effluent Desulfurization Processes. Tennessee Valley Authority. U.S. Environmental Protection Agency. EPA-600/2-75-006. Research Triangle Park, N. C. January 1975.